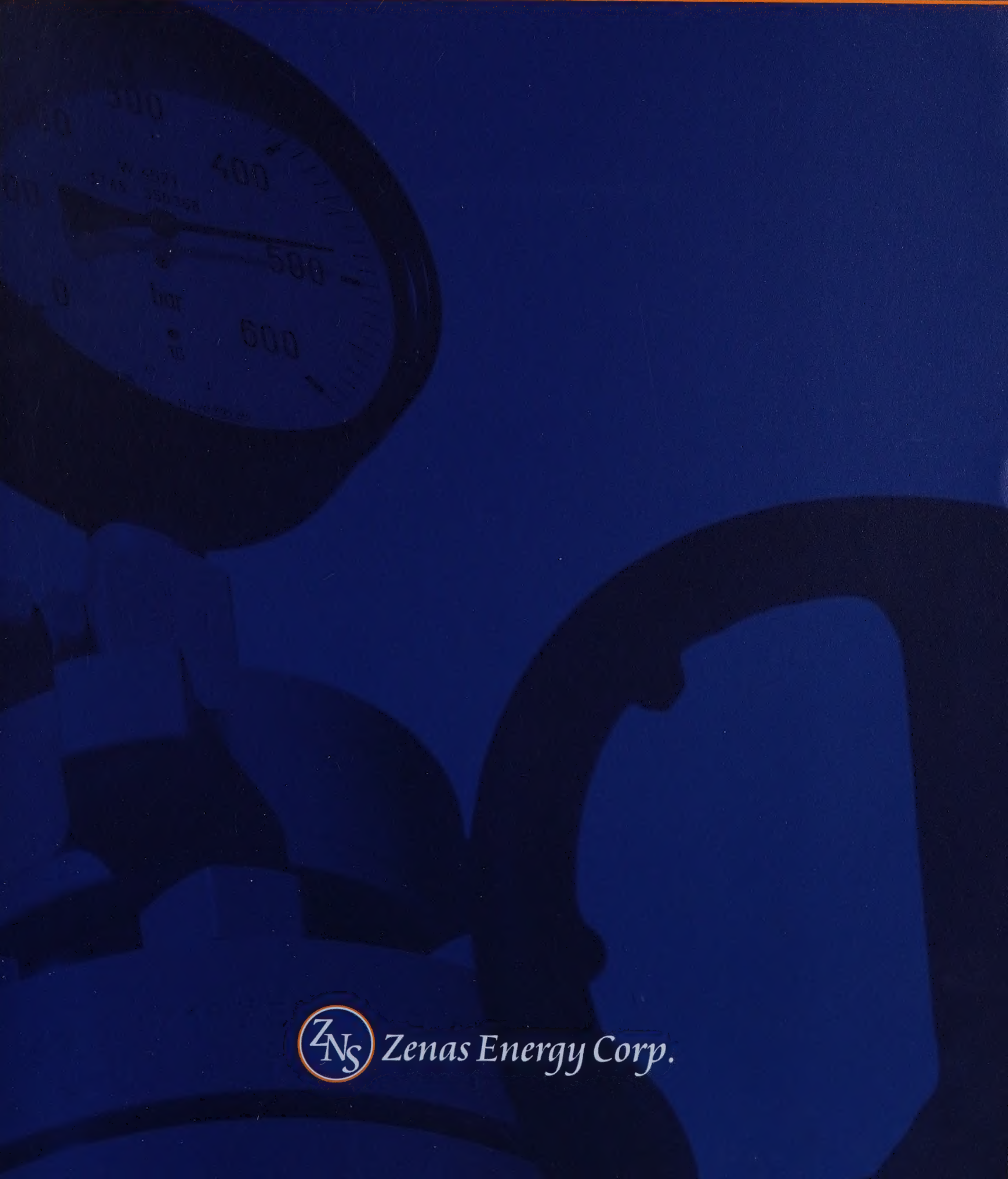
2005 ANNUAL REPORT



Zenas Energy Corp.

• **Profile** Zenas Energy Corp. is an emerging Calgary based energy company actively pursuing natural gas and crude oil through exploration, development and production in the prolific northern Alberta and northeastern British Columbia regions of the Western Canadian Sedimentary Basin. We have an aggressive three-way growth plan to acquire, exploit and explore for meaningful reserves as we strive to generate long-term value gains for our shareholders. Zenas shares trade on the Toronto Stock Exchange under the symbol ZNS.

ANNUAL MEETING

The Annual Meeting of Shareholders of Zenas Energy Corp. will be held on Wednesday, May 10, 2006 at 3:00 p.m. (Calgary time) in the Wildrose South Ballroom of the Sheraton Eau Claire located at 255 Barclay Parade S.W., Calgary, Alberta. All shareholders are cordially invited and encouraged to attend.

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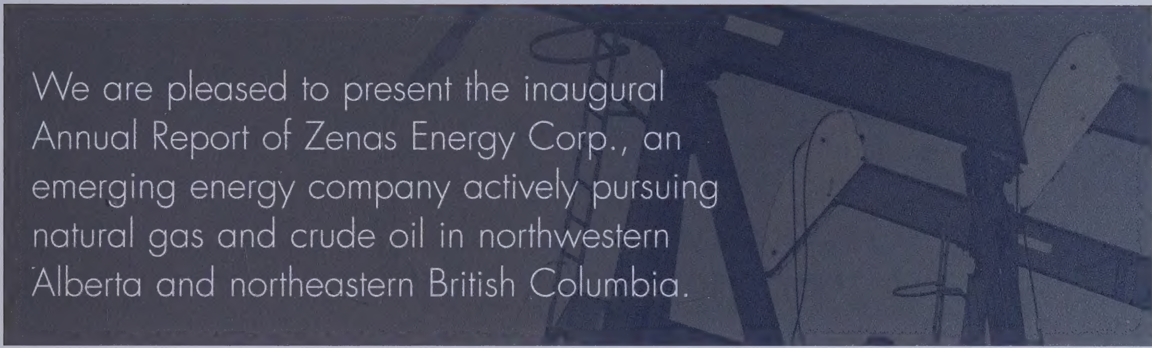

Highlights

Period Ended December 31,	2005
(000s, except per share amounts)	$
FINANCIAL	
Production revenue	**5,145**
Funds from operations[1]	**2,888**
Per share – basic and diluted	**0.10**
Net loss	**(367)**
Per share – basic and diluted	**(0.01)**
Capital expenditures	**7,971**
Working capital surplus	**55,897**
(000s)	#
SHARE DATA	
Weighted average shares outstanding	
Basic and diluted	**29,068**
Equity outstanding	
Common shares	**36,016**
Stock options	**2,489**
OPERATIONS	
Production volumes	
Natural gas (mcf/d)	**1,202**
Crude oil (bbls/d)	**276**
Natural gas liquids (bbls/d)	**26**
Combined (boe/d)	**502**
Netback ($/boe)[2]	
Average selling price	**67.33**
Royalties	**(14.59)**
Production expense	**(8.88)**
Operating netback	**43.86**

(1) Funds from operations is a non-GAAP measure that represents net income before depletion, depreciation and amortization, future taxes and other non-cash expenses. See further discussion under Non-GAAP Measures in the Management's Discussion and Analysis.

(2) Netback is a non-GAAP measure that represents specific revenue and expenses on a per unit of production basis. Natural gas has been converted to boe at a ratio of 6 mcf : 1 bbl.

Letter to Shareholders

We are pleased to present the inaugural Annual Report of Zenas Energy Corp., an emerging energy company actively pursuing natural gas and crude oil in northwestern Alberta and northeastern British Columbia ("NEBC").

• Our Corporate History

Zenas Energy Corp. commenced active oil and gas operations on August 2, 2005 when our Company was spawned through a Plan of Arrangement dated June 28, 2005. Our predecessor company, Blizzard Energy Inc. ("Blizzard"), was sold to Shiningbank Income Energy Fund ("Shiningbank") for about $3.50 per share with Blizzard shareholders receiving cash and Shiningbank units (valued at approximately $2.50 for every Blizzard share held) and common shares and warrants in Zenas (valued at approximately $1.00 per Blizzard share held). Common shares of our new Company began trading on the Toronto Stock Exchange under the symbol ZNS on August 4, 2005.

As a result of the transaction, Zenas acquired an interest in certain producing properties, seismic and undeveloped lands that were formerly owned by Blizzard. Production came primarily from two core areas: the Grande Prairie, Alberta region and NEBC. At the time of acquisition, production at Grande Prairie was concentrated from the Clair oil pool at 400 boe/d, while the Thetlaandoa, British Columbia properties were producing approximately 100 boe/d. Zenas also acquired approximately 16,000 net acres of undeveloped land, a 40 square mile 3-D seismic program and a farm-in joint venture in NEBC.

Zenas' management team has over 250 years of combined experience in the Canadian oil and gas industry and a proven record of success having worked together at Blizzard. All of Blizzard's management, professional staff and directors have carried on with Zenas, having also retained the former company's office space and office assets. With the administrative infrastructure in place, our team hit the ground running as we embarked on an exciting new adventure under Zenas Energy Corp.

• Operating Highlights

During 2005, we focused our efforts on our two core areas – the Grande Prairie region, which is medium risk light oil and multi-zone natural gas prone, and Elleh in NEBC, which is a medium risk high reward resource gas area. Operations in Grande Prairie included optimization and further development of the Clair oil pool, a gas test at Saddle Hills and a successful exploration effort in the Kakwa area. Work in NEBC was primarily geared towards planning

During 2005, we focused our efforts on our two core areas – the Grande Prairie region, which is medium risk light oil and multi-zone natural gas prone, and Elleh in NEBC, which is a medium risk high reward resource gas area.

the winter drilling program at Elleh. Although Zenas will pay 80% of this very significant 2006 first quarter capital program, we are not the operator. However, this farm-in opportunity will earn our Company a 50% working interest in over 100,000 acres of exploration land at Elleh, which includes the prolific Jean Marie resource gas play where we are assured to encounter natural gas. This winter's activities are designed to earn all of the land and to bring on-stream as much gas as possible within the constraints of having to drill "land earning" wells that will not be tied in immediately.

For the five months ended December 31, 2005, production was essentially unchanged since the Company's inception, averaging 502 boe/d. Approximately 80% of this production came from Alberta with an approximate 40% bias towards natural gas. During the period, capital activity was primarily directed to the Grande Prairie region because our NEBC properties are winter access only. Consequently, the Company drilled 7 gross (5.7 net) wells during its first five months of operations, of which 6 gross (4.7 net) wells were successful with approximately 200 boe/d net production expected to come on-stream late in the first quarter of 2006.

While operations at Grande Prairie have certainly added value, the real story for Zenas will come this winter from NEBC. Our winter program in this core area commenced with the first well at Elleh spud on January 3, 2006.

• Financial Highlights

Funds from operations for the 2005 five-month period were $2,888,000 or $0.10 per share. During the period, Zenas completed three equity financings totaling $60,980,000, thereby ensuring the Company had sufficient funding (along with an unutilized bank line of $8,800,000) to complete its current capital commitments. Capital expenditures for the period were $7,971,000 leaving Zenas with a cash and working capital surplus of $55,897,000 at December 31, 2005.

• Outlook

2006 has started with great promise for Zenas. Activities have been focused on the Elleh property where we have successfully drilled and brought on-stream a significant new gas resource. The Company had planned to drill a minimum of 16 wells, including two vertical wells and 14 under balanced long reach horizontal wells, and up to four additional horizontal wells if conditions permitted. At the time of writing this letter, it appears that we will drill only the minimum number of 16 wells and tie-in 15 wells. Although March weather has cooperated, problems with drilling services have resulted in wells taking longer and costing more than originally planned.

We anticipate initial gas production to be on-stream before the end of March and that total Company production will have grown from 500 boe/d to over 3,000 boe/d in just eight months. The new production is ahead of schedule and within the production range the Company has been forecasting.

As we look forward, we see three to five years of annual drilling at Elleh that ensures growth in production and reserves at very economic rates. We expect finding costs to drop dramatically as the "promote obligation" in the farm-in has been met and the Company will be able to high-grade locations without the concern of land retention.

Finally, both the market for natural gas and the stock market valuations of natural gas companies have experienced significant volatility. Our strategy is to stick to our plan of maintaining a growing high quality asset base and a conservative balance sheet.

I wish to thank our employees, directors and shareholders for their continued support. We are excited about the prospects for Zenas and look forward to reporting the results of our efforts as we grow the value of our Company.

On behalf of the Board of Directors,

JOHN R. ROONEY
President & Chief Executive Officer
March 16, 2006

Operations Review

Zenas has assembled an asset base that is focused on two key core areas: Grande Prairie, Alberta and northeastern British Columbia ("NEBC"). During 2005, approximately 96% of the Company's exploration, development and acquisition capital was spent in the Grande Prairie focus area. The remaining capital expenditures were applied towards survey and preparation work in NEBC.

• Grande Prairie

Our interests at Grande Prairie, located in northwestern Alberta, were acquired through a Plan of Arrangement with Blizzard Energy Inc. ("Blizzard") dated August 2, 2005, and during the first five months of operations, Zenas drilled 7 gross (5.7 net) wells. The Company has divided its Grande Prairie region into four sub-areas: Clair, Kakwa, Elmworth and Saddle Hills. During 2005, capital activities in this region totaled $6.9 million, resulting in two oil wells and one injector well drilled at Clair, three oil wells drilled at Kakwa and an unsuccessful gas target at Saddle Hills. The two oil wells at Clair were put on-stream in January 2006 at approximately 120 boe/d, while the third well will be placed on injection service by April 2006. At Kakwa, Zenas participated in the successful drilling of 3 gross (1.7 net) wells that should be put on-stream in April 2006 at approximately 150 net boe/d.

During 2005, operating netbacks for Grande Prairie averaged $46.71/boe, royalties averaged 21.1% of revenue and operating costs averaged $9.42/boe. Since acquiring the property, operating expenses increased significantly primarily as a result of rising power costs and annual equipment maintenance expenses. Electricity costs alone averaged $5.00/boe ($3.50/boe net of recoveries) during the five months ended December 31, 2005.

At December 31, 2005, Zenas had interests in approximately 12,000 gross (8,592 net) acres of undeveloped land in the Grande Prairie area. During 2006, we anticipate drilling approximately 5 gross (4.4 net) development wells in the Clair and Kakwa areas. Activities at Clair will include three 100% infill wells into the Clair V oil pool that is currently under water flood. At Kakwa, Zenas will participate in the drilling of 2 gross (1.4 net) development wells as we follow-up a development project that commenced late in the fourth quarter of 2005.

- NEBC

Zenas acquired its interest in this area through the Plan of Arrangement with Blizzard. In essence, Zenas received a small production base at Thetlaandoa plus land that was earned last winter and a farm-in agreement that gave the Company access to over 100,000 acres of prospective land in the Elleh and Thetlaandoa areas of NEBC. The farm-in agreement included an option for the Company to commit to spend $20.0 million by April 30, 2006, thereby earning a working interest in these lands. This option was exercised in August 2005, shortly after our start-up. In early 2006, Zenas amended the joint venture agreement to increase its spending commitment to $45.0 million, including the addition of four more earning wells, contractual access to gas gathering and processing facilities and removal of the swap option.

At year-end, all of the Company's production in NEBC came from the Thetlaandoa area, which totaled approximately 500 mcf/d. Two wells are scheduled to be drilled at Thetlaandoa during the first quarter of 2006, at which time further development of the area will be reviewed.

Our capital expenditures budget for 2006 is currently estimated at $50 to $55 million with approximately 90% of the program allocated to 2006 first quarter activities in NEBC. The Company had planned to drill a minimum of 16 wells, including two vertical wells and 14 under balanced long reach horizontal wells, and up to four additional horizontal wells if conditions permitted. As at the date of this report, it appears that we will drill only the minimum number of 16 wells and tie-in 15 wells. Although March weather has cooperated, problems with drilling services have resulted in wells taking longer and costing more than originally planned.

We anticipate initial gas production to be on-stream before the end of March and that total Company production will have grown from 500 boe/d to over 3,000 boe/d in just eight months. The new production is ahead of schedule and within the production range the Company has been forecasting.

The Company's 2006 capital program contemplates the drilling of up to 16 wells at Elleh located in NEBC.

Management's Discussion and Analysis

The following discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Zenas Energy Corp. This commentary is based on information available as at March 16, 2006. The discussion and analysis is a review of the operational results of the Company with disclosure of oil and gas activities in accordance with Canadian Securities Regulators National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and a review of financial results of the Company based on Canadian generally accepted accounting principles ("GAAP"). Its focus is primarily a discussion of the operational and financial performance for the period ended December 31, 2005 and should be read in conjunction with the audited financial statements and accompanying notes.

NON-GAAP MEASURES Funds from operations and operating netback are not recognized measures under GAAP. Management believes that in addition to net earnings, funds from operations and operating netback are useful supplemental measures as they demonstrate the Company's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Investors are cautioned, however, that these measures should not be construed as an alternative to net earnings determined in accordance with GAAP as an indication of Zenas' performance. The Company's method of calculating these measures may differ from other entities, and accordingly, they may not be comparable to measures used by other entities. For these purposes, Zenas defines funds from operations as cash provided by operations before changes in non-cash operating working capital and defines operating netback as revenue less royalties and operating expenses.

FORWARD-LOOKING STATEMENTS The information herein contains forward-looking statements and assumptions, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future, and accordingly, actual results may differ materially from those predicted. The forward-looking statements contained herein are as of December 31, 2005 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise, and as such, undue reliance should not be placed on forward-looking statements. The Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

• Overview

Zenas Energy Corp. ("Zenas" or the "Company") was incorporated on June 28, 2005. As a result of a Plan of Arrangement dated June 28, 2005 amongst Blizzard Energy Inc., Shiningbank Income Trust and Zenas, the Company acquired certain operating assets effective August 2, 2005. Accordingly, the reader should be aware that this Annual Report and all statistics contained herein include operating results from the properties acquired effective August 2, 2005, which equates to five months or 152 days of active oil and gas operations.

On March 16, 2006, Zenas had 36,016,000 common shares and 2,989,000 stock options issued and outstanding.

• Financial and Operating Results

QUARTERLY RESULTS

As this is the first annual reporting period (June 28, 2005 to December 31, 2005) for Zenas, there are no prior year comparatives available.

PRODUCTION AND REVENUE

Period Ended December 31,			**2005**
Market	Volume	Price	Revenue
	mcf	$/mcf	$000s
NATURAL GAS			
Alberta gas – AECO daily spot	**100,775**	**12.60**	**1,270**
British Columbia gas – Stn2 pricing[1]	**81,918**	**8.31**	**681**
Total natural gas	**182,693**	**10.68**	**1,951**
	bbls	$/bbl	$000s
CRUDE OIL AND NGLS			
Crude oil	**41,980**	**70.48**	**2,959**
NGLs	**3,982**	**59.12**	**235**
Total crude oil and NGLs	**45,962**	**69.49**	**3,194**
	boe	$/boe	$000s
COMBINED			
Total production	**76,411**	**67.33**	**5,145**

(1) 80% Stn2 average monthly index and 20% Stn2 average daily index.

Production volumes for the period ended December 31, 2005 averaged 1,202 mcf/d of natural gas, 276 bbls/d of crude oil and 26 bbls/d of natural gas liquids ("NGLs"). Production revenue for the period was $5,145,000. Wellhead prices for natural gas, crude oil and NGLs averaged $10.68/mcf, $70.48/bbl and $59.12/bbl, respectively. On a volumetric equivalent basis, 40% of Zenas' 2005 production was derived from natural gas.

All of the Company's production is sold under short-term contracts with three purchasers, which were selected through a competitive bid process. To date, Zenas has not entered into any price hedging contracts.

LAND HOLDINGS

Period Ended December 31,	2005		
	Gross	Net	Average Interest
	acres	acres	%
Developed lands	**10,485**	**6,922**	**66**
Undeveloped lands	**25,285**	**15,122**	**60**
Total lands	**35,770**	**22,045**	**62**

DRILLING ACTIVITY

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
	#	#	#	#	#	#
2005						
Oil and NGLs	**2**	**1.0**	**4**	**3.7**	**6**	**4.7**
Natural gas	–	–	–	–	–	–
Dry and abandoned	**1**	**1.0**	–	–	**1**	**1.0**
Total wells	**3**	**2.0**	**4**	**3.7**	**7**	**5.7**
Success rate (%)	**67**	**50**	**100**	**100**	**86**	**83**

ROYALTY EXPENSES

Crown royalties for the five months ended December 31, 2005 were $1,115,000. The average royalty rate as a percentage of production revenue was 21.7%, which is consistent with historic rates for the two consolidated properties. Crown royalties were estimated at $940,000 and $175,000 on the Alberta and British Columbia properties, respectively. At December 31, 2005, Zenas had no producing assets that were eligible for ARTC rebates.

OPERATING EXPENSES

Operating expenses for the five-month period totaled $678,000 after netting off processing revenue from a third party of $300,000. On a unit-of-production basis, net operating costs were $8.88/boe for the period. These costs can be broken down regionally with Alberta totaling $9.42/boe and British Columbia totaling $6.74/boe. Operating costs rose significantly due to soaring electrical power charges and annual equipment maintenance. Electricity costs alone averaged $5.00/boe ($3.50/boe net of recoveries) during the period.

STOCK-BASED COMPENSATION EXPENSE

Stock-based compensation expense totaled $896,000 for the five months ended December 31, 2005. This provision was calculated using the fair value method of accounting for stock options. In addition, future stock-based compensation expense of $3,000,000 was estimated at December 31, 2005, which will be recognized over time as the stock options vest.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses were $785,000 for the period ended December 31, 2005, which on a per unit basis totaled $10.27/boe. This rate is considered high when compared to the junior company peer group because Zenas is still in the early stages of its business plan and it has a rather small production base for its current staff complement of 20 full time office employees. By the spring of 2006, however, the Company anticipates this per unit cost to drop dramatically following the successful completion of its 2005/2006 winter drilling program, at which time Zenas should realize significant production increases. G&A expenses shown on the income statement are recorded net of a reclassification of costs attributed to exploration and development activities that totaled $331,000 and overhead recoveries of $4,000. The percentage of G&A capitalized was approximately 30% during the reporting period.

INTEREST EXPENSE AND FINANCING CHARGES

Interest expense for the five-month period was limited to standby fees and bank finance fees for the establishment of the Company's initial bank line. There were no borrowings made during the period and Zenas exited 2005 with $59,786,000 cash in the bank.

DEPLETION AND DEPRECIATION EXPENSE

Depletion and depreciation ("D&D") expense totaled $1,878,000 or $24.57/boe produced for the five months ended December 31, 2005. D&D has been computed based on reserves estimates contained in the GLJ Petroleum Consultants Ltd. reserves report dated March 1, 2006 and effective December 31, 2005. Future development costs on proved undeveloped reserves were assumed to be $1,701,000 in the reserves report. The D&D calculation excludes $13,649,000 of costs related to unproved property. In addition, the cost base being depleted at December 31, 2005 includes $1,054,000 in costs associated with asset retirement obligations.

INCOME TAX EXPENSE

At December 31, 2005, the Company had not paid or incurred any current income taxes. Future income taxes for the five-month period were estimated to be $466,000. At December 31, 2005, Zenas carried a future tax asset balance of $555,000 that consisted of tax benefits receivable of $1,021,000 on share issue expense, less the current period provision of $466,000.

FUNDS FROM OPERATIONS AND NET LOSS

Funds from operations for the five months ended December 31, 2005 totaled $2,888,000 or $0.10 per basic and diluted share. Increased production rates coupled with higher than expected commodity prices provided for the Company's strong cash flow position. Nevertheless, Zenas posted a net loss of $367,000 or $0.01 per basic and diluted share for the five-month period due to the recognition of non-cash stock compensation expense associated with stock options awarded during the period.

NETBACKS[1]

Period Ended December 31,	2005
(per unit)	$
Natural gas revenue ($/mcf)	10.68
Crude oil revenue ($/bbl)	70.48
NGLs revenue ($/bbl)	59.12
Production revenue ($/boe)	67.33
Crown royalties	(14.59)
Operating expenses before processing recoveries	(12.80)
Processing recoveries	3.92
Operating netback	43.86
Interest income	5.04
General and administrative	(10.27)
Interest	(0.41)
Large corporation tax	(0.44)
Cash flow netback	37.78
Stock-based compensation	(11.73)
Accretion expense	(0.19)
Depletion and depreciation	(24.57)
Future taxes	(6.09)
Net loss ($/boe)	(4.80)

(1) Netback is a non-GAAP financial measure.

Net loss on a unit-of-production basis (or "netback") was $4.80/boe for the five months ended December 31, 2005. Increased commodity prices had a positive effect on the results, while initially high per unit costs for administrative expenses, stock-based compensation expense and D&D expense all negatively impacted the earnings netback.

• Reserves

In a report dated March 1, 2006, GLJ Petroleum Consultants Ltd. ("GLJ"), an independent petroleum engineering firm, evaluated the crude oil, natural gas and NGLs reserves of the Company as at December 31, 2005. GLJ based their evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts and future operating plans provided by Zenas, and prepared their report in accordance with NI 51-101. The required disclosure of the reserves estimates and future net revenue of the Company as at December 31, 2005 based on forecast prices and costs, followed by similar information based on constant prices and costs, are outlined below along with the economic assumptions used in preparing those estimates.

Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES

The following table outlines the oil and gas reserves of the Company by product type on a gross (before royalties) and net (after royalties) basis. At December 31, 2005, the Company had 854,000 gross (669,000 net) proved boes and 1,185,000 gross (927,000 net) proved plus probable boes.

	Crude Oil		Natural Gas		NGLs	
	Gross	Net	Gross	Net	Gross	Net
	mbbls	mbbls	mmcf	mmcf	mbbls	mbbls
Proved						
Developed producing	272	226	1,080	790	17	12
Developed non-producing	174	149	1,006	717	45	30
Undeveloped	–	–	–	–	–	–
Total proved	446	375	2,086	1,507	62	42
Probable	147	126	930	674	29	19
Total proved plus probable	593	501	3,016	2,181	91	61

RECONCILIATION OF COMPANY INTEREST RESERVES BY PRINCIPAL PRODUCT

The reconciliation of the Company's net proved, probable and proved plus probable reserves for December 31, 2005 is as follows:

	Crude Oil				Natural Gas				NGLs			
	Net Proved Producing	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved Producing	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved Producing	Net Proved	Net Probable	Net Proved Plus Probable
	mboe	mboe	mboe	mboe	mmcf	mmcf	mmcf	mmcf	mboe	mboe	mboe	mboe
Jun. 30, 2005	**387**	**387**	**95**	**482**	**951**	**951**	**231**	**1,182**	**17**	**17**	**4**	**21**
Jul. 2005 production	**(9)**	**(9)**	**–**	**(9)**	**(44)**	**(44)**	**–**	**(44)**	**(1)**	**(1)**	**–**	**(1)**
Aug. 1, 2005	**378**	**378**	**95**	**473**	**907**	**907**	**231**	**1,138**	**16**	**16**	**4**	**20**
Revisions	**(64)**	**(40)**	**(33)**	**(73)**	**356**	**388**	**30**	**418**	**5**	**6**	**–**	**6**
Drilling extensions	**–**	**101**	**33**	**134**	**–**	**158**	**44**	**202**	**–**	**6**	**2**	**8**
Exploration discoveries	**–**	**49**	**52**	**101**	**–**	**816**	**625**	**1,441**	**–**	**38**	**23**	**61**
Production	**(42)**	**(42)**	**–**	**(42)**	**(183)**	**(183)**	**–**	**(183)**	**(4)**	**(4)**	**–**	**(4)**
Dec. 31, 2005	**272**	**446**	**147**	**593**	**1,080**	**2,086**	**930**	**3,016**	**17**	**62**	**29**	**91**

NET PRESENT VALUES OF FUTURE NET REVENUE

The net present values of future net revenue of the Company's reserves at various discount rates on a before and after tax basis are outlined below. At December 31, 2005, the Company had approximately $36,343,000 of tax deductions available to reduce future taxable income, and as a result, the reduction to the net present values (10% discount rate) for future income taxes was approximately 8.3%.

	Before Income Taxes Discounted At				
	0%	5%	10%	15%	20%
(000s)	$	$	$	$	$
Proved					
Developed producing	15,682	14,478	13,462	12,595	11,847
Developed non-producing	11,334	9,488	8,217	7,272	6,535
Undeveloped	–	–	–	–	–
Total proved	27,016	23,966	21,679	19,867	18,382
Probable	9,649	7,541	6,215	5,283	4,585
Total proved plus probable	36,665	31,507	27,894	25,150	22,967

	After Income Taxes Discounted At				
	0%	5%	10%	15%	20%
(000s)	$	$	$	$	$
Proved					
Developed producing	15,682	14,478	13,462	12,595	11,847
Developed non-producing	10,265	8,490	7,283	6,394	5,707
Undeveloped	–	–	–	–	–
Total proved	25,947	22,968	20,745	18,989	17,554
Probable	7,930	5,996	4,812	4,000	3,403
Total proved plus probable	33,877	28,964	25,557	22,989	20,957

TOTAL FUTURE NET REVENUE

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved and proved plus probable reserves:

	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
(000s)	$	$	$	$	$	$	$	$
Proved								
2006	13,547	3,012	1,016	1,701	–	7,818	210	7,608
2007	10,389	2,128	1,154	–	92	7,015	721	6,294
2008	6,932	1,317	1,255	–	–	4,360	138	4,222
2009	5,076	874	1,083	–	–	3,119	–	3,119
2010	3,866	615	1,213	–	–	2,038	–	2,038
2011	2,877	428	1,264	–	298	887	–	887
2012	679	131	198	–	21	329	–	329
2013	395	73	108	–	17	197	–	197
2014	311	61	79	–	18	153	–	153
2015	259	52	62	–	–	145	–	145
Remainder	1,622	315	316	–	36	955	–	955
	45,953	9,006	7,748	1,701	482	27,016	1,069	25,947
Proved plus probable								
2006	15,195	3,406	1,141	2,154	–	8,494	575	7,919
2007	12,544	2,608	1,342	–	36	8,558	1,199	7,359
2008	8,911	1,729	1,447	–	57	5,678	551	5,127
2009	6,640	1,195	1,231	–	–	4,214	299	3,915
2010	5,266	876	1,353	–	–	3,037	85	2,952
2011	4,198	654	1,463	–	–	2,081	79	2,002
2012	3,492	514	1,558	–	304	1,116	–	1,116
2013	1,128	207	327	–	7	587	–	587
2014	750	124	220	–	15	391	–	391
2015	662	107	209	–	18	328	–	328
Remainder	4,024	703	1,039	–	101	2,181	–	2,181
	62,810	12,123	11,330	2,154	538	36,665	2,788	33,877

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

The economic parameters, as determined by GLJ, assumed in preparing the forecast prices and costs reserves report are as follows:

NATURAL GAS PRICE FORECAST – EFFECTIVE JANUARY 1, 2006

		Alberta Plant Gate				
		Spot				
Year	AECO C Spot Then Current	Constant 2006 $	Then Current	ARP	Aggregator	Alliance
	$CDN/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu
2001	6.21	6.81	6.07	5.41	5.30	5.61
2002	4.04	4.24	3.88	3.88	3.83	3.82
2003	6.66	6.94	6.49	6.13	5.89	6.69
2004	6.88	6.98	6.70	6.31	6.16	6.44
2005E	8.58	8.60	8.42	8.35	8.36	8.45
2006 Q1	10.45	10.20	10.20	10.20	10.15	11.05
2006 Q2	10.35	10.10	10.10	10.10	10.00	9.90
2006 Q3	10.45	10.20	10.20	10.20	10.10	9.90
2006 Q4	11.05	10.80	10.80	10.80	10.75	11.10
2006 Full Year	10.60	10.35	10.35	10.35	10.25	10.50
2007	9.25	8.80	9.00	9.00	9.00	8.90
2008	8.00	7.45	7.75	7.75	7.75	7.45
2009	7.50	6.85	7.25	7.25	7.25	6.90
2010	7.20	6.40	6.95	6.95	6.95	6.65
2011	6.90	6.05	6.65	6.65	6.65	6.35
2012	6.90	5.90	6.65	6.65	6.65	6.35
2013	7.05	5.95	6.80	6.80	6.80	6.50
2014	7.20	5.95	6.95	6.95	6.95	6.65
2015	7.40	6.00	7.15	7.15	7.15	6.80
2016	7.55	6.00	7.30	7.30	7.30	6.95
2017+	+2%/yr	6.00	+2%/yr	+2%/yr		

CRUDE OIL AND NATURAL GAS LIQUIDS PRICE FORECAST – EFFECTIVE JANUARY 1, 2006

			West Texas Intermediate Crude Oil at Cushing Oklahoma		Crude Oil (40 API, 0.3%S) at Edmonton		Alberta Natural Gas Liquids (Then Current Dollars)			
Year	**Inflation**	**Bank of Canada Average Noon Exchange Rate**	Constant 2005 $	Then Current	Constant 2005 $	Then Current	Spec Ethane	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus
	%	$US/$CDN	$US/bbl	$US/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl
2001	2.6	0.646	29.14	25.97	44.21	39.40	n/a	31.85	31.17	42.48
2002	2.2	0.637	28.52	26.08	44.10	40.33	n/a	21.39	27.08	40.73
2003	2.8	0.721	33.24	31.07	46.71	43.66	n/a	32.14	34.36	44.23
2004	1.8	0.768	43.08	41.38	55.13	52.96	n/a	34.70	39.97	54.07
2005E	2.2	0.825	57.86	56.60	70.65	69.11	n/a	42.55	51.41	69.45
2006 Q1	2.0	0.850	56.00	56.00	65.25	65.25	35.50	41.75	48.25	66.00
2006 Q2	2.0	0.850	56.00	56.00	65.25	65.25	35.25	41.75	48.25	66.00
2006 Q3	2.0	0.850	57.50	57.50	67.00	67.00	35.50	43.00	49.50	67.75
2006 Q4	2.0	0.850	58.00	58.00	67.50	67.50	37.50	43.25	50.00	68.25
2006 Full Year	2.0	0.850	57.00	57.00	66.25	66.25	36.00	42.50	49.00	67.00
2007	2.0	0.850	54.00	55.00	62.75	64.00	31.25	41.00	47.25	65.25
2008	2.0	0.850	49.00	51.00	57.00	59.25	27.00	38.00	43.75	60.50
2009	2.0	0.850	45.25	48.00	52.50	55.75	25.25	35.75	41.25	56.75
2010	2.0	0.850	43.00	46.50	50.00	54.00	24.25	34.50	40.00	55.00
2011	2.0	0.850	40.75	45.00	47.25	52.25	23.25	33.50	38.75	53.25
2012	2.0	0.850	40.00	45.00	46.50	52.25	23.25	33.50	38.75	53.25
2013	2.0	0.850	40.00	46.00	46.25	53.25	23.75	34.00	39.50	54.25
2014	2.0	0.850	40.00	46.75	46.25	54.25	24.25	34.75	40.25	55.25
2015	2.0	0.850	40.00	47.75	46.50	55.50	25.00	35.50	41.00	56.50
2016	2.0	0.850	40.00	48.75	46.25	56.50	25.50	36.25	41.75	57.75
2017+	2.0	0.850	40.00	+2%/yr	46.25	+2%/yr	Escalate at 2.0% per year			

Constant Prices and Costs

SUMMARY OF OIL AND GAS RESERVES

The following table outlines the oil and gas reserves of the Company by product type using constant price and cost assumptions on a gross (before royalties) and net (after royalties) basis. The constant price and cost scenarios have slightly higher oil and natural gas reserves compared to the forecast reserves. The increase was due to high December 31, 2005 prices for both commodities being held constant compared to the declining forecast pricing assumptions.

	Crude Oil		Natural Gas		NGLs	
	Gross	Net	Gross	Net	Gross	Net
	mbbls	mbbls	mmcf	mmcf	mbbls	mbbls
Proved						
Developed producing	296	248	1,112	813	18	12
Developed non-producing	175	151	1,009	719	46	31
Undeveloped	–	–	–	–	–	–
Total proved	471	399	2,121	1,532	64	43
Probable	175	152	970	700	30	20
Total proved plus probable	646	551	3,091	2,232	94	63

NET PRESENT VALUES OF FUTURE NET REVENUE

The net present values of future net revenue of the Company's reserves at various discount rates on a before and after tax basis are as follows:

	Before Income Taxes Discounted At				
	0%	5%	10%	15%	20%
(000s)	$	$	$	$	$
Proved					
Developed producing	18,934	17,146	15,676	14,451	13,417
Developed non-producing	14,458	11,854	10,070	8,761	7,754
Undeveloped	–	–	–	–	–
Total proved	33,392	29,000	25,746	23,212	21,171
Probable	13,779	10,499	8,404	6,947	5,882
Total proved plus probable	47,171	39,499	34,150	30,159	27,053

	After Income Taxes Discounted At				
	0%	5%	10%	15%	20%
(000s)	$	$	$	$	$
Proved					
Developed producing	18,934	17,146	15,676	14,451	13,417
Developed non-producing	12,353	9,980	8,386	7,236	6,365
Undeveloped	–	–	–	–	–
Total proved	31,287	27,126	24,062	21,687	19,782
Probable	10,478	7,731	6,043	4,901	4,083
Total proved plus probable	41,765	34,857	30,105	26,588	23,865

TOTAL FUTURE NET REVENUE

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved reserves using constant prices and costs:

	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
(000s)	$	$	$	$	$	$	$	$
Proved								
2006	13,221	2,911	1,016	1,701	–	7,593	128	7,465
2007	10,962	2,243	1,105	–	90	7,524	891	6,633
2008	8,143	1,568	1,162	–	–	5,413	490	4,923
2009	6,372	1,119	965	–	–	4,288	344	3,944
2010	5,039	824	1,058	–	–	3,157	139	3,018
2011	3,896	602	1,080	–	60	2,154	113	2,041
2012	2,988	426	1,105	–	229	1,228	–	1,228
2013	533	106	92	–	15	320	–	320
2014	412	85	65	–	15	247	–	247
2015	336	71	50	–	–	215	–	215
Remainder	1,858	373	205	–	27	1,253	–	1,253
	53,760	10,328	7,903	1,701	436	33,392	2,105	31,287

	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
(000s)	$	$	$	$	$	$	$	$
Proved plus probable								
2006	14,816	3,289	1,141	2,154	–	8,232	479	7,753
2007	13,244	2,751	1,290	–	35	9,168	1,402	7,766
2008	10,487	2,061	1,347	–	55	7,024	1,001	6,023
2009	8,342	1,532	1,105	–	–	5,705	797	4,908
2010	6,867	1,175	1,187	–	–	4,505	576	3,929
2011	5,692	921	1,260	–	–	3,511	557	2,954
2012	4,735	730	1,318	–	30	2,657	377	2,280
2013	3,858	565	1,326	–	36	1,931	217	1,714
2014	2,915	389	1,270	–	13	1,243	–	1,243
2015	850	146	173	–	45	486	–	486
Remainder	4,492	817	712	–	254	2,709	–	2,709
	76,298	14,376	12,129	2,154	468	47,171	5,406	41,765

FINDING AND DEVELOPMENT COSTS

Period Ended December 31,	2005	Including Future Development
(000s)	$	$
CAPITAL EXPENDITURES		
Acquisitions	**–**	–
Exploration and development	**7,971**	9,672
Total capital expenditures	**7,971**	9,672
	mboe	mboe
RESERVES		
Proved		
Acquisitions	**–**	–
Exploration and development	**385**	385
Total added reserves	**385**	385
Proved plus probable		
Acquisitions	**–**	–
Exploration and development	**579**	579
Total added reserves	**579**	579
	$/boe	$/boe
FINDING AND DEVELOPMENT COSTS		
Proved		
Acquisitions	**–**	–
Exploration and development	**20.70**	25.12
Total finding and development costs	**20.70**	25.12
Proved plus probable		
Acquisitions	**–**	–
Exploration and development	**13.76**	16.70
Total finding and development costs	**13.76**	16.70

RESERVE LIFE INDEX

The reserve life index of Zenas has been calculated using 2006 estimated production volumes and gross proved and proved plus probable reserves using forecast prices and costs, all of which were taken from the December 31, 2005 GLJ reserves report. The reserve life index of the Company as at December 31, 2005, on a boe basis, was 3.9 years for proved reserves and 5.4 years for proved plus probable reserves.

	Proved	Proved Plus Probable	Expected 2006 Production	Proved	Proved Plus Probable
(000s)				years	years
Crude oil (bbls)	446	593	119	3.7	5.0
Natural gas (mcf)	2,086	3,016	515	4.0	5.8
NGLs (bbls)	62	91	13	4.8	7.0
Total (boe)	856	1,187	218	3.9	5.4

Liquidity and Capital Resources

Excluding the assets acquired through the Plan of Arrangement on June 28, 2005, Zenas invested $7,971,000 from cash in the bank on capital activities during the five months ended December 31, 2005. The allocation of these expenditures is set out in the following table:

Period Ended December 31,	2005
(000s)	$
Land	**21**
Geological and geophysical	**80**
Drilling, completions and equipping	**7,342**
Facilities and gathering systems	**200**
Other	**328**
Total capital expenditures	**7,971**

During the period, the Company raised $64,018,000 from three equity issues. After share issue expenses totaling $3,038,000, Zenas deposited $60,980,000 in the bank that virtually ensured the completion of its 2005 and 2006 planned capital programs. At December 31, 2005, the Company had a cash and working capital surplus of $55,897,000 and no bank debt. Zenas has access to a total of $8,800,000 in revolving term credit facilities with a Canadian chartered bank, and at December 31, 2005, $nil had been drawn on these facilities. Borrowing under the facilities revolves until May 31, 2006 with annual extension periods available at the request of Zenas and subject to the bank's approval.

Critical Estimates

The proved natural gas reserves used in determining the Company's depletion rates, the borrowing base from its bank and the ceiling test are based on management's best estimates of reserves, which are subject to uncertainty. Through the use of geological, geophysical and engineering data, the accumulations of crude oil, natural gas and NGLs are examined to determine quantities available for future production given existing operating conditions and technology. The evaluation of these reserves is an ongoing and dynamic process impacted by current production, development activities and changing economic conditions, and as a result, the reserves are estimates that are subject to variability.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded. Income taxes are calculated using the liability method of accounting for income taxes. Under this method, all existing temporary differences are scheduled and the future income tax balance is calculated using tax rates in effect when temporary differences are expected to reverse. Forecasts of estimated net revenue streams are utilized to calculate the future tax provision and,

as such, are subject to revisions, both upwards and downwards, that are not known at this time. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of future taxes determined at a point in time, and to the extent that these differences are created, they can impact the charge against earnings for future taxes.

The stock option plan provides for granting of options to directors, officers, employees and consultants. Compensation costs attributable to share options granted are measured at estimated fair value at the grant date and expensed over the term of the option with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. Determination of the estimated fair market value is based on the estimated volatility of the price of the Company's common shares, the expected hold period of the option to the exercise date and the estimated risk-free interest rate.

• Business Risks and Uncertainties

Zenas is exposed to numerous risks and uncertainties associated with the exploration for and development and acquisition of crude oil, natural gas and NGLs. Primary risks include the uncertainty associated with exploration drilling, changes in production practices, product pricing, industry competition and government regulations.

Drilling activities are subject to numerous technical risks and uncertainties of discovering commercially productive reservoirs. Zenas attempts to offset exploration risk by utilizing trained professional staff and conducting extensive geological and geophysical analysis prior to drilling wells.

Zenas monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Zenas maintains a level of liability, property and business interruption insurance that is believed to be adequate for the Company's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims.

• Corporate Governance

Zenas' corporate governance practices comply with all existing guidelines for effective corporate governance established by the Toronto Stock Exchange. A full description of Zenas' approach to corporate governance can be found in the Company's 2006 Information Circular.

The Company has established disclosure controls and procedures to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the time periods specified by securities regulations and that information required to be disclosed is communicated to management on a timely basis. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of these controls and procedures and have concluded that they are adequate and effective as at the end of the period covered by this Annual Report, in all material respects.

• SEDAR

Effective August 4, 2005, Zenas became a Toronto Stock Exchange listed company. As a result, additional public information can be accessed on the Company's website at www.zenasenergy.ca and on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Hal Metcalfe

HAL A. J. METCALFE
Executive Vice-President Finance & Chief Financial Officer
March 16, 2006
Calgary, Alberta

Management's Report

To the Shareholders of Zenas Energy Corp.

The accompanying financial statements of Zenas Energy Corp. and all information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada and within the framework of the Company's significant accounting policies as described in the notes to the financial statements. The financial statements reflect management's best estimates and judgements based on currently available information within reasonable limits of materiality.

Financial information presented throughout the Annual Report has been prepared and reviewed by management to ensure it is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial statements. Management maintains appropriate systems of internal control to provide reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records are properly maintained to provide reliable financial information for the preparation of financial statements.

Independent auditors are appointed by the shareholders of the Company to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review of the system of internal controls and included such tests and other procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility through its Audit Committee. The Audit Committee meets with management and the independent auditors to satisfy itself that management's responsibilities are properly discharged, to review the financial statements and recommend the financial statements be presented to the Board of Directors for approval.

The financial statements, including the notes to the financial statements, have been approved by the Board of Directors on the recommendation of the Audit Committee.

J Rooney

JOHN R. ROONEY
President & Chief Executive Officer
March 16, 2006
Calgary, Canada

Hal Metcalfe

HAL A.J. METCALFE
Executive Vice-President Finance & Chief Financial Officer

Auditors' Report

To the Shareholders of Zenas Energy Corp.

We have audited the balance sheet of Zenas Energy Corp. as at December 31, 2005 and the statement of earnings (loss) and deficit and cash flows for the period from incorporation on June 28, 2005 to December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and the results of its operations and its cash flows for the period from incorporation on June 28, 2005 to December 31, 2005 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants
March 16, 2006
Calgary, Canada

Balance Sheet

As at December 31,	2005
(000s)	$
ASSETS (notes 5 and 10)	
Current	
Cash and cash equivalents	59,786
Accounts receivable	2,574
Prepaid expenses	239
	62,599
Property and equipment (notes 3, 4 and 10)	35,729
Future income tax asset (note 8)	555
	98,883
LIABILITIES	
Current	
Accounts payable and accrued liabilities	6,702
Asset retirement obligations (note 6)	1,069
	7,771
Commitments (note 10)	
SHAREHOLDERS' EQUITY	
Share capital (note 7)	90,583
Contributed surplus (note 7)	896
Deficit	(367)
	91,112
	98,883

See accompanying notes to the financial statements.

On behalf of the Board of Directors,

FRANK J. GUIDOLIN
Director

GEORGE W. WATSON
Director

Statement of Earnings (Loss) and Deficit

Period Ended December 31,	2005
(000s, except per share amounts)	$
Revenue	
Production revenue	5,145
Royalties	(1,115)
	4,030
Other income	385
	4,415
Expenses	
Production	678
General and administrative	785
Stock-based compensation (note 7)	896
Finance charges	31
Accretion of asset retirement obligations (note 6)	15
Depletion and depreciation	1,878
	4,283
Income before income taxes	132
Income taxes (note 8)	
Current taxes	33
Future income taxes	466
	499
Net loss for the period	(367)
Retained earnings, beginning of period	–
Deficit, end of period	(367)
Net loss per share (note 7)	
Basic and diluted	(0.01)

See accompanying notes to the financial statements.

Statement of Cash Flows

Period Ended December 31,	2005
(000s)	$
Operating activities	
Net loss for the period	(367)
Add non-cash items	
Non-cash stock-based compensation (note 7)	896
Accretion of asset retirement obligations	15
Depletion and depreciation	1,878
Future income taxes	466
	2,888
Net change in non-cash working capital (note 9)	(264)
	2,624
Investing activities	
Additions to property and equipment	(7,971)
Net change in non-cash working capital (note 9)	4,153
	(3,818)
Financing activities	
Issue of common shares (net of issue expenses)	60,980
	60,980
Increase in cash and cash equivalents	59,786
Cash and cash equivalents, beginning of period	–
Cash and cash equivalents, end of period	59,786

Supplemental disclosure of cash flow information (note 9)

See accompanying notes to the financial statements.

Notes to Financial Statements

December 31, 2005

1 • Nature of Operations

Zenas Energy Corp. ("Zenas" or the "Company") was incorporated with nominal share capital under the laws of the Province of Alberta on June 28, 2005.

2 • Summary of Significant Accounting Policies

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles and a summary of accounting policies follows.

a) Capitalized Costs

The Company follows the full cost method of accounting for oil and gas operations whereby all costs relating to the acquisition of, exploration for and development of oil and gas reserves are capitalized in a single Canadian cost centre. Such costs include lease acquisition, lease rentals on undeveloped properties, geological and geophysical, drilling both productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities.

Gains or losses are not recognized under the disposition of oil and gas properties unless such a disposition would result in a change in the depletion rate by 20% or more. Gains and losses are recognized upon the disposition of other assets.

b) Depletion and Depreciation

All costs of acquisition, exploration and development of oil and gas reserves, associated tangible plant and equipment costs (net of salvage value), and estimated costs of future development of proved undeveloped reserves are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves as determined by independent engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted to the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties and seismic costs on undeveloped lands are initially excluded from oil and gas properties for the purpose of calculating depletion. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

Computer and office furniture and equipment are depreciated on a straight-line basis over five years.

c) Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying value of the related long-lived asset. The liability is carried on the balance sheet at its discounted present value and is subsequently adjusted for the passage of time, which is recognized as an operating expense in the statement of earnings (loss) on a basis consistent with depletion and depreciation of the underlying assets. The fair value of the obligation is periodically adjusted for revisions in either the timing or the amount of the original estimated cash flows associated with the liability.

2 • Summary of Significant Accounting Policies (CONTINUED)

d) Ceiling Test

The Company calculates its ceiling test by comparing the carrying value of property and equipment to the sum of undiscounted cash flows expected to result from the future production of proved reserves. Cash flows are based on third party quoted forward prices, adjusted for transportation and quality. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the cost of unproved properties. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess is recorded as additional depletion and depreciation in the statement of earnings (loss).

e) Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with maturities not exceeding 90 days or that are cashable after 30 days. Cash equivalents at December 31, 2005 totaled $59,000,000 and earn interest at effective annual rates of 3.0% to 3.25%.

f) Revenue Recognition

Oil and natural gas sales are recognized as revenue when the commodities are delivered to purchasers.

g) Joint Interests

Substantially all of the Company's exploration, development and production activities are conducted jointly with others, and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

h) Stock-Based Compensation

The Company has a stock-based compensation plan, which is described in note 7. Options issued are accounted for in accordance with the fair value method of accounting for stock-based compensation. The associated compensation expense is charged to earnings (loss) and a corresponding increase in contributed surplus, based on an estimate of the fair value determined using a Black-Scholes option pricing model at the date of the grant. Consideration paid to the Company on the exercise of stock options is credited to share capital. At the time of exercise, the related amounts previously credited to contributed surplus are also transferred to share capital. Stock options issued to directors, employees and consultants are amortized to income over their vesting life.

i) Measurement Uncertainty

The amount recorded for depletion and depreciation of oil and gas properties, the provision for future asset retirement obligations and the ceiling test calculation are based on estimates of gross proved reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

2 • Summary of Significant Accounting Policies (CONTINUED)

j) Per Share Information

Per share information is calculated using the treasury stock method. Under this method, the diluted weighted average number of common shares is calculated assuming that the proceeds from the exercise of outstanding and in-the-money options and unrecognized future stock-based compensation expense are used to purchase common shares at the estimated average market price.

k) Flow-Through Common Shares

A portion of the Company's exploration and development activities are financed through proceeds received from the issue of flow-through shares or warrants. Under the terms of the flow-through issues, the tax attributes of the resource expenditures related to exploratory and development activities are renounced to the subscribers as incurred. To recognize the foregone tax benefits to the Company, the carrying value of the shares or warrants issued is reduced and the future income tax liability increased by the tax effect of the tax benefits renounced to subscribers. The foregone tax benefit is recognized at the time the renouncement is filed provided there is reasonable assurance that the expenditures will be incurred.

l) Future Income Taxes

The Company follows the liability method to account for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities, and measured using the substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse.

m) Financial Instruments

The carrying value of financial instruments, consisting of cash and cash equivalents, accounts receivable and accounts payable, approximate their fair values due to their short term to maturity.

3 • Transfer of Assets

GRANDE PRAIRIE AND NORTHEASTERN BRITISH COLUMBIA ("NEBC") PROPERTIES

On August 2, 2005, the Company acquired the working interests of Blizzard Energy Inc. ("Blizzard") in the Clair and Kakwa areas of Alberta, undeveloped lands in the Saddle Hills and Elmworth areas of Alberta and all of Blizzard's production and undeveloped lands in the Elleh and Thetlaandoa areas of NEBC. The acquisition also included a 40 square mile 3-D seismic program and a joint venture farm-in in NEBC. At the time of the transaction, Zenas and Blizzard were related companies, resulting in a transfer of the assets to Zenas from Blizzard at their carrying value as follows:

Net Assets Received	
(000s)	$
Property and equipment	**29,086**
Asset retirement obligations	**(504)**
Shares issued (18,957,083 common and 18,957,083 transaction warrants (note 7))	**28,582**

4 • Property and Equipment

As at December 31,	2005		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
(000s)	$	$	$
Oil and gas properties	**37,587**	**1,877**	**35,710**
Office assets	**20**	**1**	**19**
	37,607	**1,878**	**35,729**

At December 31, 2005, oil and gas properties included $13,649,000 relating to undeveloped properties and seismic costs, which have been excluded from the depletion and depreciation calculation. Future development costs on proved undeveloped reserves of $1,701,000 at December 31, 2005 and $331,000 in capitalized general and administrative costs relating to exploration and development activities were included in the depletable cost base.

The Company performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of its petroleum and natural gas interests. It was determined that there was no impairment using the prices in the following table:

Year	Crude Oil Price	Natural Gas Price	NGLs Price
	$/bbl	$/mcf	$/bbl
2006	62.51	10.63	48.97
2007	60.38	9.23	46.67
2008	55.64	7.92	41.81
2009	52.14	7.41	38.65
2010	50.40	7.10	37.07
2011	48.68	6.79	35.47
2012	52.25	6.74	33.97
Thereafter	+2%yr	+2%/yr	+2%/yr

5 • Bank Loan

The Company has a $7,000,000 extendible revolving term credit facility (#1) from a Canadian chartered bank, of which $nil was drawn at December 31, 2005. This facility bears interest at the bank's prime rate (5.00% at December 31, 2005), payable monthly in arrears. The Company may also borrow by way of bankers' acceptances, which are subject to a stamping fee of 1.25%. In addition, the Company has a $1,800,000 temporary revolving credit facility (#2) from the same bank, of which $nil was drawn at December 31, 2005. This facility bears interest at the bank's prime rate plus 0.50%. Borrowing under both facilities revolves until May 31, 2006 with annual extension periods available at the request of the borrower and subject to the bank's approval. These facilities are subject to an annual review and re-determination of the Company's borrowing base by the bank.

So long as the loans remain revolving and the borrowing base supports the facilities outstanding, there are no repayment requirements. In the event the revolving period is not extended, the credit facilities shall be converted to term facilities with a term not exceeding five years. Under the terms of the loan agreement, the Company is subject to certain financial and non-financial covenants.

Collateral pledged for the two facilities consists of a first floating charge demand debenture in the amount of $50,000,000 over all of the property of the Company.

6 • Asset Retirement Obligations

At December 31, 2005, the Company had recorded a liability for future site restoration and abandonment of $1,054,000. In addition, no liabilities were settled, $15,000 of accretion expense was recognized and no revisions in estimated future cash requirements were recorded. The total undiscounted amount of the estimated future cash requirements was $2,005,000 at December 31, 2005, calculated using an inflation factor of 2.5% per year and adjusted for the expectation that costs would occur at the end of the reserves' useful lives primarily in the years 2013 to 2017. The undiscounted estimate has been discounted to the present value of $1,069,000 at December 31, 2005 using a credit adjusted risk-free rate of 7.0%.

(000s)	$
Obligation assumed on transfer of assets (note 3)	**504**
Increase in obligation	**67**
Change in estimate	**483**
Accretion	**15**
Obligation at December 31, 2005	**1,069**

7 • Share Capital

a) Authorized

Unlimited number of voting common shares, without par value.
Unlimited number of preferred shares to be issued in series.

b) Common Shares Issued

	Shares	Amount
(000s)	#	$
Balance at inception on June 28, 2005	–	–
Issued to Blizzard shareholders in exchange for transferred properties (note 3)	**18,957**	**28,582**
Issued for cash	**13,100**	**58,080**
Issued upon exercise of transaction warrants	**3,959**	**5,938**
Share issue expenses	–	**(3,038)**
Estimated income tax benefits on share issue expenses	–	**1,021**
Balance at December 31, 2005	**36,016**	**90,583**

On July 25, 2005, the Company completed a private placement through its wholly owned subsidiary, Zenas Finance Corp. ("Zenas Finance"), by issuing 4,000,000 common shares at a price of $1.50 per share for proceeds of $6,000,000.

On August 2, 2005, the Company issued 4,000,000 common shares to Zenas Finance shareholders in exchange for all of their shares in Zenas Finance. Also on August 2, 2005, the Company issued 18,957,083 common shares and 18,957,083 transaction warrants to Blizzard shareholders in exchange for certain producing properties, seismic and undeveloped land of Blizzard, which were recorded at their carrying value of $28,582,000 (note 3). The transaction warrants allowed the holders to acquire 0.211 common shares of Zenas at $1.50 per share for each whole Zenas share received. On September 1, 2005, all unexercised warrants, which totaled 196,332, expired. Therefore, 3,958,516 common shares were issued as a result of the exercised warrants for total proceeds of $5,938,000. Share issue expenses associated with the transaction were $276,000 and future income tax benefits on these expenses totaled $92,000.

7 • Share Capital (CONTINUED)

b) Common Shares Issued (continued)

On October 12, 2005, the Company completed a private placement by issuing 7,500,000 common shares at a price of $5.60 per share for gross proceeds of $42,000,000. Share issue expenses associated with this transaction were $2,233,000, while future income tax benefits on these expenses were $751,000.

On December 5, 2005, the Company completed a private placement by issuing 1,600,000 common shares on a flow-through basis at a price of $6.30 per share for gross proceeds of $10,080,000. Share issue expenses associated with this transaction were $529,000, while future income tax benefits on these expenses were $178,000.

c) Stock Options

The Company has a stock option plan that provides for the issuance of options to its directors, officers, employees and consultants to acquire up to 10% of the issued and outstanding common shares. Vesting of options and exercise prices are set by the Board of Directors at the time of grant. The dates on which options expire are also set by the Board of Directors at the time of grant and cannot exceed ten years. In connection with this plan, the Company has reserved 2,489,000 common shares for future issuance. The Company has issued stock options to acquire common shares through its stock option plan of which the following were outstanding at December 31, 2005:

	Options Outstanding	Weighted Average Exercise Price
	#000s	$
Outstanding at June 28, 2005	–	–
Granted August 11, 2005	**1,542**	**5.14**
Granted December 5, 2005	**947**	**4.95**
Outstanding at December 31, 2005	**2,489**	**5.07**
Options exercisable at December 31, 2005	**386**	**5.14**

The stock options granted on August 11, 2005 vest as to one-quarter on the date of the grant and one-quarter for each of the first three anniversary dates from the date of the grant. The stock options granted on December 5, 2005 vest 100% on January 1, 2009. All of the outstanding options expire five years from the date of the grant.

The fair value of common share options granted to date was estimated to be $3,896,000 as at the date of grant using the Black-Scholes option pricing model and the following assumptions:

Risk free interest rate (%)	**3.00**
Expected life (years)	**3.00**
Expected volatility (%)	**40.00**
Expected dividend yield (%)	**0.00**

The estimated fair value of the options is amortized to expense over the options' vesting period on a straight-line basis. As a result, $896,000 was recognized as stock-based compensation expense for the five-month period ended December 31, 2005, with a corresponding increase to contributed surplus.

d) Per Share Amounts

The net loss per common share and diluted net loss per common share were calculated using the weighted average number of shares outstanding of 29,068,000 for the five months ended December 31, 2005.

8 • Income Taxes

The actual income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial corporate tax rates to earnings before income taxes. These differences are explained as follows:

Period Ended December 31,	2005
(000s)	$
Net income before income taxes	132
Statutory income tax rate	33.62%
Expected income tax expense	44
Increase (decrease) in income taxes from:	
Non-deductible Crown charges	249
Resource allowance	(143)
Non-deductible stock-based compensation costs	301
Other	15
Future and current income tax expense	466
Large corporation tax	33
Income tax expense	499

As at December 31,	2005
(000s)	$
Differences between tax base and reported amounts for depreciable assets	472
Provision for asset retirement obligations	(6)
Tax benefits on share issue expenses	(1,021)
Net future income tax asset	(555)

At December 31, 2005, the Company had unused resource tax pool balances of approximately $36,343,000, which are available for reducing future income taxes.

A future tax liability of $3,389,000 on the flow-through share issue completed in December 2005 was not recognized until the filing of the renounciation, which was in January 2006.

9 • Cash Flow Information

Cash was provided or (used) for changes in non-cash working capital as follows:

Period Ended December 31,	2005
(000s)	$
Accounts receivable	(2,574)
Prepaid expenses	(239)
Accounts payable and accrued liabilities	6,702
Net change	3,889
Net change by activity	
Operating	(264)
Financing	4,153
Net change	3,889

The following shows the actual cash amount paid:

Period Ended December 31,	2005
(000s)	$
Cash interest paid	31
Cash taxes paid	–

10 • Commitments

The Company has a drilling commitment with a senior oil and gas producer to spend at least $45,000,000 in NEBC by spring breakup 2006. Collateral pledged as security for the commitment consists of a $20,000,000 fixed and floating charge debenture over all of the Company's oil and gas properties, which is subordinated to the Company's bank.

The Company is committed to payments under operating leases for office space of $224,000 for each of 2006 and 2007, and $19,000 for January 2008.

Corporate Information

Board of Directors

JAMES S. ARTINDALE
Chairman
Zenas Energy Corp.

LARRY G. EVANS(2)(3)
Chairman
Glacier Energy Limited

FRANK J. GUIDOLIN(1)
President
Petroaudit Consultants Inc.

DAVID R. MACKENZIE(1)(3)
Independent Businessman

DOUGLAS G. MANNER(2)(3)
Vice-President & Chief Operating Officer
Westside Energy Corp.

JOHN R. ROONEY
President & Chief Executive Officer
Zenas Energy Corp.

ROBERT R. ROONEY(2)
Corporate Director

GEORGE W. WATSON(1)
Chief Executive Officer
Critical Control Solutions Corp.

(1) Audit & Finance Committee Member
(2) Technical Committee Member
(3) Human Resources & Governance Committee Member

Officers

JOHN R. ROONEY
President & Chief Executive Officer

MICHAEL MACHALSKI
Executive Vice-President &
Chief Operating Officer

HAL A.J. METCALFE
Executive Vice-President Finance &
Chief Financial Officer

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BANKER
Scotiabank

EVALUATION ENGINEERS
GLJ Petroleum Consultants Ltd.

TRANSFER AGENT
Inquiries regarding change of address, registered shareholdings, stock transfers or lost certificates should be directed to:

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Phone: (403) 233-2801

STOCK EXCHANGE LISTING
Toronto Stock Exchange
Trading Symbol: ZNS

ABBREVIATIONS

bbl	barrel
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mcfe	thousand cubic feet equivalent
mcfe/d	thousand cubic feet equivalent per day
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
mmcfe	million cubic feet equivalent
mmcfe/d	million cubic feet equivalent per day
2-D	two dimensional
3-D	three dimensional

CONVERSION OF UNITS

1.0 acre	=	0.40 hectares
2.5 acres	=	1.0 hectare
1.0 bbl	=	0.159 cubic metres
6.29 bbls	=	1.0 cubic metre
1.0 foot	=	0.3048 metres
3.281 feet	=	1.0 metre
1.0 mcf	=	28.2 cubic metres
0.035 mcf	=	1.0 cubic metres
1.0 mile	=	1.61 kilometres
0.62 miles	=	1.0 kilometres

Natural gas is equated to oil on the basis of 6 mcf = 1 boe

www.zenasenergy.ca